Electricity

Electricity consumption nearly doubles in the IEO2001 projections. Developing nations in Asia and in Central and South America are expected to lead the increase in world electricity use.

In the *International Energy Outlook 2001* (*IEO2001*) reference case, worldwide electricity consumption is projected to increase at an average annual rate of 2.7 percent from 1999 to 2020 (Table 20). The most rapid growth in electricity use is projected for developing Asia, at 4.5 percent per year, and by 2020 developing Asia is expected to consume more than twice as much electricity as it did in 1999. China's electricity consumption is projected to triple, growing by an average of 5.5 percent per year from 1999 to 2020. The expected growth rate for electricity use in Central and South America is 4.0 percent per year, and in the developing world as a whole the projected average growth rate is 4.2 percent per year.

The projections for electricity consumption in the developing world depend primarily on assumptions with regard to growth in population and per capita income. In countries where population is expected to remain stable, such as China, per capita income growth is the more important component of electricity demand growth. In countries where substantial population growth is anticipated, such as the nations of South America, per capita income growth is less important as a determinant of growth in electricity demand.

Electricity consumption in the industrialized world is expected to grow at a more modest pace of 1.8 percent per year, considerably lower than has been seen in the past. (The three industrialized economies of North America—Canada, Mexico, and the United States—accounted for roughly one-third of the world's electricity market in 1999.) In addition to expected slower growth in population and economic activity in the industrialized nations, market saturation and efficiency gains for some electronic appliances are expected to slow the growth of electricity consumption.

The *IEO2001* reference case forecast is framed by low and high economic growth case projections. In the *IEO2001* high economic growth case, annual growth in global electricity consumption is projected to average 3.3 percent from 1999 to 2020. In the low economic growth case, electricity consumption is projected to grow by an average of 1.7 percent per year (Figure 77).

In 1999, coal provided 34 percent of the energy used for electricity generation throughout the world (Table 21), accounting for the largest market share among the

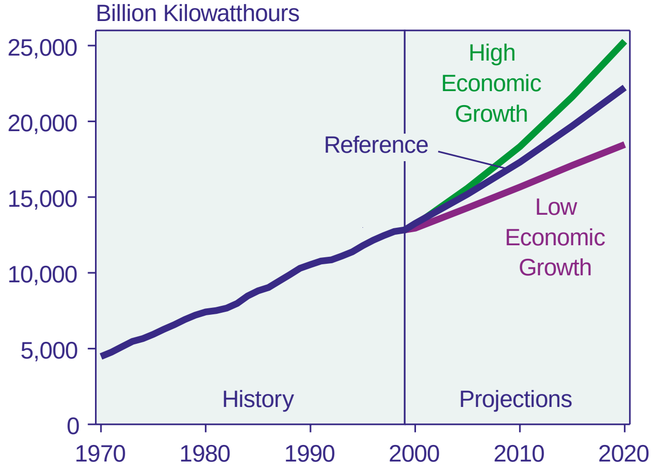
Table 20. World Net Electricity Consumption by Region, 1990-2020
(Billion Kilowatthours)

Region	History		Projections				
	1990	1999	2005	2010	2015	2020	Average Annual Percent Change, 1999-2020
Industrialized Countries	**6,385**	**7,517**	**8,580**	**9,352**	**10,112**	**10,888**	**1.8**
United States	2,817	3,236	3,761	4,147	4,484	4,804	1.9
EE/FSU	**1,906**	**1,452**	**1,622**	**1,760**	**1,972**	**2,138**	**1.9**
Developing Countries	**2,258**	**3,863**	**4,988**	**6,191**	**7,615**	**9,203**	**4.2**
Developing Asia	1,259	2,319	3,088	3,883	4,815	5,856	4.5
China	551	1,084	1,533	2,035	2,635	3,331	5.5
India	257	424	545	656	798	949	3.9
South Korea	93	233	294	333	386	437	3.0
Other Developing Asia	357	578	716	858	996	1,139	3.3
Central and South America	449	684	844	1,035	1,268	1,552	4.0
Total World	**10,549**	**12,833**	**15,190**	**17,303**	**19,699**	**22,230**	**2.7**

Note: EE/FSU = Eastern Europe and the former Soviet Union.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, January 2001). **Projections:** EIA, World Energy Projection System (2001).

Figure 77. World Net Electricity Consumption in Three Cases, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, January 2001). **Projections:** EIA, World Energy Projection System (2001).

energy fuels.[20] Coal is expected to remain the most widely used fuel for electricity generation through 2020, when its share of the total is projected to be about 31 percent (Figure 78). China and the United States accounted for one-half of the world's steam coal consumption in 1999, and in 2020 (assuming no changes in current environmental laws and policies) they are expected to consume nearly two-thirds of all the coal used to generate electricity.

Nuclear power accounted for 17 percent of the energy used for electricity generation in 1999 and natural gas 19 percent. In the reference case forecast, nuclear is expected to lose and natural gas to gain market share. The nuclear share is projected to fall to 12 percent in 2020, and the gas share is projected to increase to 26 percent. Renewables, including hydropower, are projected to account for 21 percent of total energy use for electricity generation in 2020, up slightly from their 20-percent share in 1999.

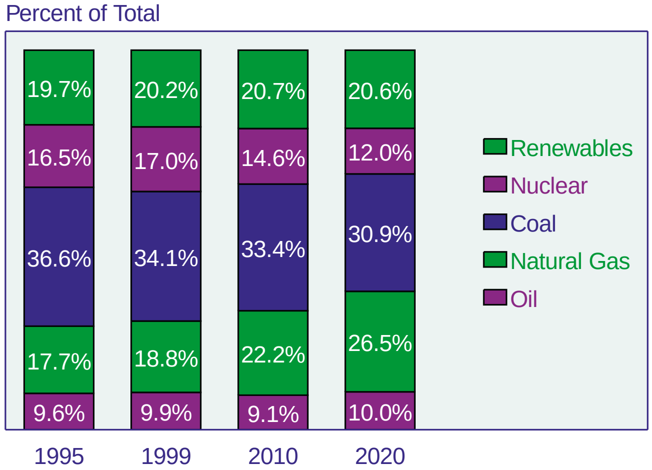
Table 21. World Energy Consumption for Electricity Generation by Region and Fuel, 1995-2020
(Quadrillion Btu)

Region and Fuel	History		Projections			
	1995	1999	2005	2010	2015	2020
Industrialized	**77.1**	**83.8**	**91.6**	**97.2**	**103.5**	**108.0**
Oil	5.7	6.5	5.4	5.3	5.5	5.9
Natural Gas	9.7	11.6	15.6	18.3	23.1	27.4
Coal	27.7	29.5	32.1	33.4	34.0	34.3
Nuclear	19.4	20.6	20.9	20.9	20.5	19.1
Renewables	14.7	15.6	17.5	19.4	20.4	21.3
EE/FSU	**26.4**	**23.8**	**25.9**	**27.0**	**28.9**	**30.8**
Oil	2.8	2.4	3.1	3.5	4.2	4.7
Natural Gas	10.6	10.3	11.1	12.3	14.4	15.9
Coal	7.4	5.4	5.4	4.5	3.3	2.8
Nuclear	2.5	2.7	3.2	3.1	3.1	2.8
Renewables	3.1	3.0	3.2	3.5	4.0	4.5
Developing	**38.1**	**40.9**	**52.3**	**63.1**	**75.0**	**86.6**
Oil	5.1	5.7	6.9	8.3	10.0	12.0
Natural Gas	4.8	6.0	8.4	11.0	13.6	16.4
Coal	16.8	15.8	20.4	24.7	29.2	32.6
Nuclear	1.4	1.9	2.6	3.4	4.1	5.1
Renewables	10.1	11.5	14.1	15.8	18.2	20.5
Total World	**141.7**	**148.4**	**169.8**	**187.3**	**207.4**	**225.4**
Oil	13.6	14.6	15.4	17.0	19.7	22.5
Natural Gas	25.1	27.9	35.2	41.7	51.0	59.7
Coal	51.9	50.7	57.8	62.5	66.5	69.7
Nuclear	23.3	25.3	26.7	27.4	27.7	27.1
Renewables	27.9	30.0	34.8	38.7	42.5	46.4

Note: EE/FSU = Eastern Europe and the former Soviet Union.

Sources: **History:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, January 2001). **Projections:** EIA, World Energy Projection System (2001).

Figure 78. Fuel Shares of Energy Use for Electricity Generation, 1995, 1999, 2010, and 2020



Sources: **1995 and 1999:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, January 2001). **2010 and 2020:** EIA, World Energy Projection System (2001).

Oil has played a decreasing role in electricity generation for several decades. As recently as 1978, oil accounted for nearly one-fourth of the world's energy consumption for power generation, but its use has since been largely displaced by nuclear power and natural gas. Oil's share of the global electricity fuel market was 10 percent in 1999 and is projected to remain at 10 percent in 2020.

The remainder of this chapter provides a brief overview of world electricity generation and fuel use, followed by highlights of developments in national electricity industries in the United States (where electricity deregulation is proceeding in many States) and the rest of the world.

Primary Fuel Use for Electricity Generation

Natural Gas

Natural gas is becoming the fuel of choice for new electricity generation investment around the globe. Over the 1999 through 2020 forecast period, natural gas use for electricity generation is expected to more than double (Table 21), as technologies for gas-fired generation continue to improve and ample natural gas reserves are exploited. Contributing developments include a desire to move away from reliance on nuclear power and coal in Western Europe; uncertainty about national and international policies (such as the Kyoto Protocol) that could affect coal use; an expected decline in nuclear power capacity in the United States; increasing substitution of natural gas for coal in Eastern Europe and the former Soviet Union (FSU); and fuel diversification to reduce reliance on hydroelectricity among the developing nations of South America.

The FSU and the Middle East each account for 35 percent of the world's proved natural gas reserves [***1***]. The FSU accounted for more than one-third of natural gas usage in electricity generation worldwide in 1999, and natural gas provided 51 percent of the energy used for electricity generation in the region. In 2020, natural gas is projected to account for 58 percent of the electricity generation market in the FSU. Relying increasingly on imports from Russia, the nations of Eastern Europe are also expected to increase their reliance on natural gas for electricity generation, from 10 percent in 1999 to 26 percent in 2020.

Natural gas use in the electricity generation sector is also expected to grow rapidly in North America and Western Europe. In the United States the natural gas share of the electricity fuel market is expected to double from 14 percent in 1999 to 28 percent in 2020, and in Canada the gas share is expected to grow from 3 percent in 1999 to 10 percent in 2020. Although a sharp increase in natural gas prices in late 2000 has cast some doubt on energy strategies that would rely entirely on natural gas for new generating capacity, it is expected that the higher prices will lead to more spending on exploration and development in the longer term, reducing prices and restoring the competitiveness of gas as a generation fuel. In addition, imports from Canada are expected to provide a growing supply of natural gas to U.S. generators.

The most rapid increase in natural gas use for electricity generation in the industrialized world is projected for Western Europe. After the oil crisis of 1973, European nations actively discouraged the use of natural gas for electricity generation and instead favored domestic coal and nuclear power over dependence on natural gas imports. In 1975 a European Union directive restricted the use of gas in new power plants, and the natural gas share of the electricity market in Western Europe fell from 9 percent in 1977 to 5 percent in 1981, where it remained for most of the 1980s. In the early 1990s, the growing availability of reserves from the North Sea and increased imports from Russia and North Africa lessened concerns about gas supply in the region, and the EU directive was repealed. In 1999 natural gas held a 14-percent share of the electricity fuel market in Western Europe. That share is projected to grow to 28 percent in 2020.

The relative accessibility of natural gas resources will in large measure determine Europe's reliance on gas as a fuel for electricity generation. Almost three-quarters of the world's natural gas reserves are in the former Soviet union and the Middle East. For some regions, including Western Europe, increased access to natural gas by pipeline or LNG tanker will be needed in order for the expected increases in gas-fired electricity generation to be realized.

In Central and South America natural gas accounted for 11 percent of the electricity fuel market in 1999. Its share is projected to grow to 32 percent in 2020. Hydropower is the major source of electricity supply in South America at present, but environmental concerns, cost overruns on large hydropower projects in the past, and electricity shortfalls during periods of drought have prompted South American governments to view natural gas as a means of diversifying their electricity supplies. A continent-wide natural gas pipeline system is emerging in South America, which will transport Argentine and Bolivian gas to Chile and Brazil.

Coal

In 2020, coal is expected to account for 31 percent of the world's electricity fuel market, slightly lower than its 34-percent share in 1999. The United States accounted for 38 percent of all coal use for electricity generation in 1999 and developing Asia 25 percent. In the *IEO2001* forecast, the coal share of U.S. electricity generation is expected to decline slightly, to 44 percent in 2020 from 51 percent in 1999; and in developing Asia the coal share is projected to decline to 52 percent in 2020 from 54 percent in 1999.

Reliance on coal for electricity generation is also expected to be reduced in other regions. In Western Europe, for example, coal accounted for 23 percent of the electricity fuel market in 1999 but is projected to have only a 15-percent share in 2020. Similarly, in Eastern Europe and the FSU (EE/FSU), coal's 23-percent share of the electricity fuel market in 1999 is projected to fall to 9 percent in 2020.

Nuclear Power

The nuclear share of energy use for electricity production is also expected to decline in most regions of the world as a result of operational safety concerns, waste disposal issues, concerns about nuclear arms proliferation, and the economics of nuclear power. In the United States, the nuclear share is projected to drop from 20 percent of the electricity fuel market in 1999 (second behind coal) to 12 percent in 2020. In Canada, where the nuclear share of the market has been declining since 1984, its 14-percent share in 1999 is projected to decline to 13 percent in 2020. In Western Europe, the nuclear share of the electricity fuel market is projected to fall from 35 percent in 1999—more than any other energy source—to 24 percent in 2020. (Finland and France are alone among Western Europe's nuclear power producers in remaining committed to expanding their nuclear power programs.)

In Japan, nuclear power accounted for 33 percent of the energy used for electricity generation in 1999. That share is expected to rise to 38 percent by 2020 in the *IEO2001* forecast. In the EE/FSU region, the nuclear share is projected to decline from 12 percent in 1999 to 9 percent in 2020.

Nuclear power contributes very little to electricity generation in the developing nations of Central and South America, Africa, and the Middle East, and it is expected to contribute little in 2020. Among South American nations, only Argentina and Brazil were nuclear power producers in 1999. In Africa, only South Africa generated electricity from nuclear power in 1999. There are no nuclear power plants in operation in the Middle East, although one is under construction in Iran.

In contrast to the rest of the world's regions, in developing Asia nuclear power is expected to play a growing role in electricity generation. China, India, Pakistan, South Korea, and Taiwan currently have nuclear power programs, and the nuclear share of the region's electricity fuel market is expected to remain stable at 7 to 8 percent from 1999 through 2020. China is expected to account for most of the region's nuclear power capacity additions.

Hydroelectricity and Other Renewables

Renewable energy, including hydropower, accounted for 20 percent of the world's energy use for electricity generation in 1999. Its share is expected to rise only slightly, to 21 percent, in 2020. Of the world's consumption of renewable energy for electricity production in 1999, the United States and Canada together accounted for almost 30 percent of the total, Central and South America 19 percent (despite generating just 5 percent of the world's electricity), Western Europe 19 percent, and developing Asia 15 percent.

In 1999, renewables accounted for 11 percent of electricity production in the United States and 62 percent in Canada, where hydroelectric power has been extensively developed. Their shares are generally expected to be maintained through 2020. In North America and throughout the world, generation technologies using nonhydroelectric renewables are expected to improve over the forecast period, but they still are expected to be relatively expensive in the low price environment assumed in the *IEO2001* reference case.

Hydroelectricity is most widely used for electricity generation in Central and South America, and renewables accounted for 75 percent of the region's electricity fuel market in 1999. However, recent experiences with drought, cost overruns, and the negative environmental impacts of several large-scale hydroelectric projects have reduced the appeal of hydropower in South America, and the renewable share of electricity generation in Central and South America is expected to decline to 55 percent by 2020 as the region works to diversify its electricity fuel mix.

Most of Western Europe's renewable energy consumption consists of hydroelectricity. Norway led Europe in hydroelectricity production in 1999, accounting for 26 percent of the region's total [***2***], followed by Sweden at 15 percent and France at 14 percent. Renewables in total accounted for 22 percent of the region's electricity market, and their share is expected to increase to 26 percent in 2020. Some European nations, particularly Denmark and Germany, are also actively developing their nonhydroelectric renewable energy resources, notably wind.

Some near-term growth in renewable energy use is expected in developing Asia, particularly in China, where the 18,200-megawatt Three Gorges Dam and a number of other hydropower projects are expected to become operational during the forecast period. Developing Asia relied on renewables for 20 percent of its electricity production in 1999, and that share is expected to remain stable through 2020.

Oil

The role of oil in the world's electricity generation market has been on the decline since the second oil price shock that started in 1979. Oil accounted for 23 percent of electricity fuel use in 1977, but in 1999 its share was only 10 percent. Energy security concerns, as well as environmental considerations, have led most nations to reduce their use of oil for electricity generation. In regions where oil continues to hold a significant share of the generation fuel market, however, such as the FSU and the Middle East, increases in its share are expected. As a result, the oil share of world energy use for electricity production is projected to remain at 10 percent in 2020.

Developing Asia accounted for 17 percent of the world's consumption of oil for electricity generation in 1999, when 10 percent of its electricity fuel use consisted of oil (down from 29 percent in 1977). The oil share of electricity fuel consumption in developing Asia is expected to decline slightly, to 9 percent in 2020. In the FSU region, which accounted for 14 percent of the world's consumption of oil for electricity generation in 1999, oil's share is projected to increase to 17 percent in 2020 from 11 percent in 1999. In the Middle East, oil supplied 35 percent of the energy used for electricity generation in 1999, and its share is projected to grow to 38 percent in 2020.

Regional Highlights

United States

Industry Consolidation Continues

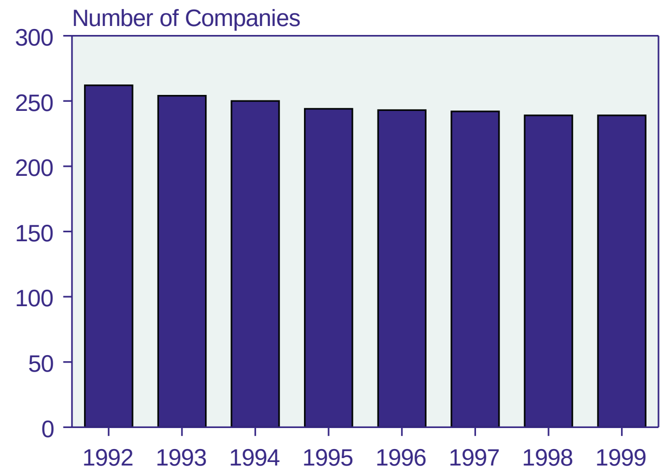
Between 1996 and 1998 there were an average of 12 merger and acquisition announcements annually in the U.S. electricity industry. There are currently 239 investor-owned public utilities, down by 23 (9 percent) since 1992 (Figure 79). Employment in the U.S. electric service industry has fallen from 440,000 jobs in 1992 to 360,000 in 1999. Employment reductions have been an anticipatory reaction to industry consolidation as well as a result of many mergers and acquisitions themselves. The latest round of industry consolidation has occurred amid a wave of deregulation at both the State and Federal levels.

It should be noted that this is not the first time the industry has gone through a period of great change. Shortly after Thomas Edison gave birth to the industry when he opened his Pearl Street generator in New York in 1882, scores of electricity companies were established. By the early 1900s, Chicago alone had 47 electricity companies [***3***]. In the 1920s a wave of industry consolidation ensued reaching a peak of over 300 mergers per year during the mid-1920s [***4***]. By 1929, seven holding companies accounted for 60 percent of U.S. generating capacity [***5***]. Growing economies of scale of larger generation units in part helped move this consolidation along.

During the 1930s, several major holding companies went bankrupt leading to a Federal Trade Commission investigation and the enactment of the Public Utility Holding Company Act. Subsequently, several hundred holding companies were spun off, and by the early 1950s there were well over 500 investor-owned utilities (IOUs). But once again the industry consolidated, and the number of IOUs fell to roughly 270 in the late 1960s.

As in the 1930s, the most recent wave of merger and acquisition activity stems in part from Federal policy reforms. The Public Utility Regulatory Policies Act of 1978 (PURPA) required transmission companies to interconnect with and buy whatever capacity any

Figure 79. Investor-Owned Utilities in the United States, 1992-1999



Source: Energy Information Administration, *Electric Sales and Revenues*, DOE/EIA-0540 (Washington, DC, various years).

facility meeting the criteria for a "qualifying facility"[21] had to offer, and to pay that facility the utility's own incremental or avoided cost of production [*6*]. Open access was pushed a step further with the passage of the Energy Policy Act of 1992 (EPACT), which allowed for wholesale power competition by creating a new class of wholesale generator and expanded the power of the Federal Energy Regulatory Commission (FERC) to order open transmission access [*7*].

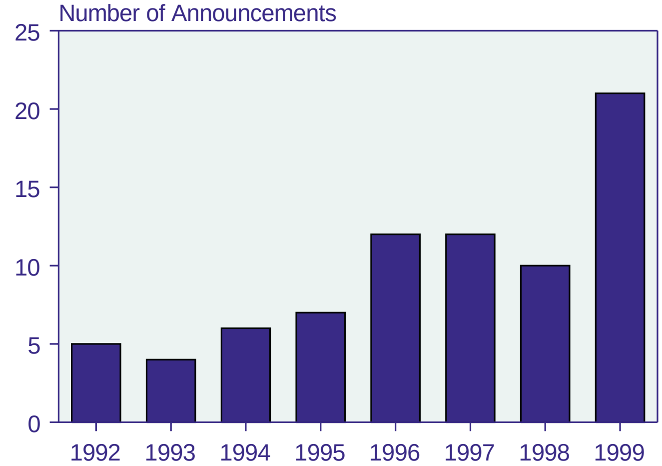
EPACT also promoted eventual competition at the retail level. Based on the mandate derived from EPACT, the FERC issued Orders 888 and 889. Order 888 required all public utilities that own, control, or operate facilities used for transmitting electricity in interstate commerce to provide open access to transmission services for other power producers [*8*]. Order 889 required the establishment of an electronic trading system similar to the one that had evolved in the natural gas market only a few years earlier.

The corporate response to these policy changes was the creation of a rapidly growing independent power industry, which made for a more competitive atmosphere in generation. In 1998, there were 109 independent power producers active in the United States [*9*], and they accounted for about 7 percent of existing capacity. More than half of all new capacity additions in the United States are expected to be supplied by independent power producers [*10*].

The FERC may have also eased the way for many mergers and acquisitions when it adopted a new merger and acquisition policy in 1996. The agency adopted the Department of Justice/Federal Trade Commission merger guidelines as a screening device to determine whether a proposed merger would cause an unacceptable increase in market power. In addition, the updated policy reflects the important role that competition is expected to play in protecting the public interest since the passage of EPACT and the implementation of open transmission access.

The new policy uses a quantitative screen, employing an Herfindahl-Hirschman index, to determine a potential merger's impact on competition.[22] The new policy also attempts to reduce the procedural steps involved in a review along with the review time for most mergers to 12-15 months. Since the new policy was implemented, more merger and acquisition approvals have been made by the FERC, and announcements of mergers and acquisitions have accelerated [*11*] (Figure 80).

Figure 80. Mergers and Acquisitions in the U.S. Electricity Industry, 1992-1999



Source: Ausma Tomserics, Edison Electric Institute, personal communication, March 13, 2001.

What distinguishes the current era of industry consolidation from earlier post-war consolidation is the size of the companies involved in the merger and acquisitions. Up until the 1990s, post-war mergers and acquisitions generally involved the purchase of relatively small IOUs. The 1990s, in contrast, have seen some of the largest companies in the industry involved on both sides of the merger and acquisition transaction. During the past decade, U.S. electricity companies have also made substantial acquisitions overseas, particularly in the United Kingdom, Australia, and South America; and foreign companies are now beginning to invest in U.S. electricity. The current wave of industry consolidation is also distinct in that the industry has also merged extensively with the natural gas industry.

In the current wave of consolidation, acquiring companies have been willing to pay a steep premium over book values, indicating perhaps that certain operational synergies may be realized through this expansion. By 2000, this premium had increased to roughly double the book value of the acquired companies (Figure 81).

Several large mergers took place or were announced in 2000. The largest involved the FPL Group of Florida and Entergy Corporation of Louisiana. The debt and equity value of the merged companies equals $27 billion, and the combined company will become the biggest utility in the United States. Both companies are major producers of nuclear power, which also continues a trend among the nuclear power industry toward greater concentration (see discussion in the Nuclear Power chapter

[21] A "qualifying facility" is defined as a cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the FERC.

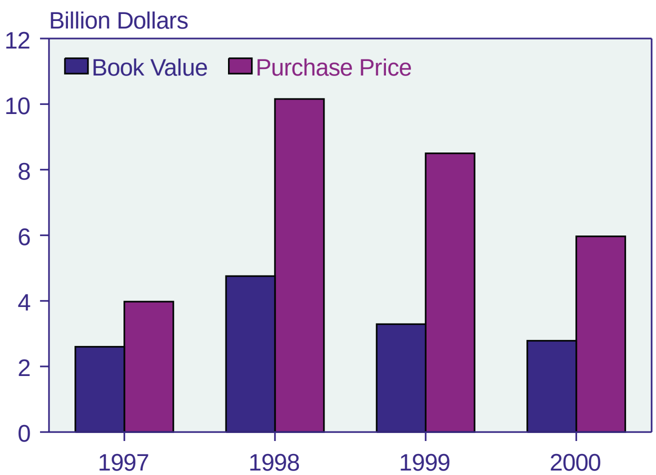
[22] The Herfiindahl-Hirschman index is a commonly accepted measure of market concentration. It is calculated by squaring the market share of each firm competing in the market and then summing the resulting numbers. The index takes into account the relative size and disribution of firms in a market and approaches zero when a market consists of a large number of firms of relatively equal size. For more infomation, see U.S. Department of Justice, web site www.usdoj.gov/atr/testimony/hhi.htm.

of this report). Together Entergy and FP&L will account for 11 percent of U.S. nuclear power generation. The value of the transaction was estimated at $13.9 billion [***12***]. In April 2000, Entergy and Koch Industries (of Kansas) agreed to merge Koch's natural gas pipeline operations with Entergy's power trading and fuel procurement operations.

In August 2000, FirstEnergy Corporation of Ohio agreed to acquire GPU, Inc., of New Jersey. When the acquisition is completed, FirstEnergy will become the sixth largest energy company in the United States [***13***]. GPU, which has divested most of its power plants over the last few years, is now largely a distribution company. The value of the transaction is estimated at $4.5 billion in cash and stock and another $7.4 billion in debt for a total of $11.9 billion. GPU serves customers in New Jersey and Pennsylvania; FirstEnergy services customers in Ohio and Pennsylvania.

The next largest merger announcement in 2000 also involved two very large utility companies and holders of nuclear generation assets. In October 2000, Unicom (Illinois) and PECO Energy (Pennsylvania) completed their merger. The combined company name is Exelon. Exelon will have $12 billion in revenues and will be the largest nuclear power company in the United States, accounting for 17 percent of total capacity. The value of the transaction was estimated at $7.8 billion [***14***].

Figure 81. Book Values and Purchase Prices of Acquisitions in the U.S. Electricity Industry, 1997-2000

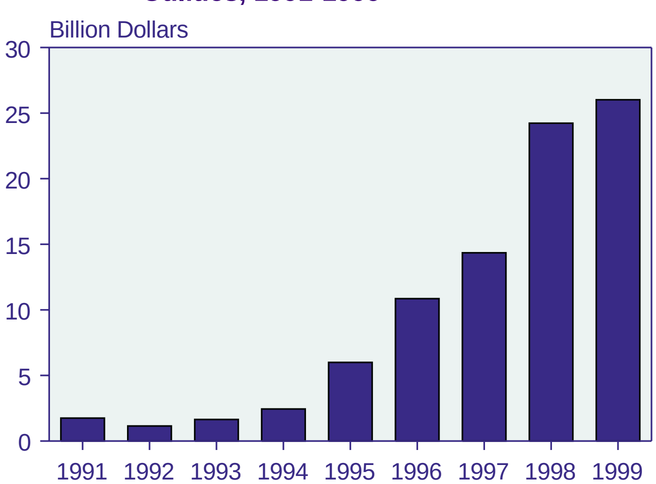


Note: Transactions are as of October 6, 2000.
Source: Edison Electric Institute, *Divestiture Action and Analysis* (various isues).

International Investment in U.S. Electricity Industry Grows

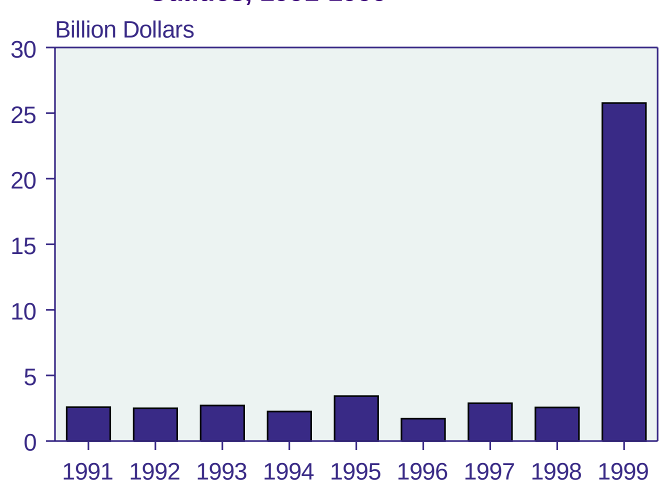
Although U.S. companies have invested heavily overseas since the early 1990s (Figure 82), foreign companies have until recently invested little in U.S. electricity. However, several companies from the United Kingdom (UK) have recently acquired U.S. electricity assets, a development heretofore rare in the U.S. electricity industry (Figure 83). The largest of these acquisitions involved Scottish Power's purchase of PacifiCorp of Oregon. The value of the acquisition was estimated at $12.9 billion. The merger was completed November 1999.

Figure 82. U.S. Direct Investment in Overseas Utilities, 1991-1999



Note: The utility investments shown include, in addition to electricity, natural gas distribution and sanitary services; however, the sharp rise in investments from 1995 through 1999 is almost entirely the result of investments in overseas electric utilities by U.S. companies.
Source: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (various issues).

Figure 83. Foreign Direct Investment in U.S. Utilities, 1991-1999



Note: The utility investments shown include, in addition to electricity, natural gas distribution and sanitary services; however, the sharp rise in investments during 1999 is largely the result of investments in U.S. electric utilities by foreign companies.
Source: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (various issues).

U.S. Electricity Deregulation: The California Experience

California's recent experience with electricity deregulation could have repercussions for the many governments around the world that are seeking to achieve electricity reform. Just as the earlier experience with reforms in the United Kingdom encouraged others to adopt similarly aggressive attempts at liberalizing electricity markets, the recent Californian experience with electricity reform may give some pause about reforming too quickly or ambitiously . . . or at all.[a] Motivating California's electricity reform efforts was the desire to reduce some of the highest electricity rates in the United States. In 1996, California's average electricity revenue per kilowatthour sold, at 9.54 cents, was 38 percent higher than the average U.S. rate.[b] California's residential consumers paid 36 percent more than the average U.S. residential consumer, and industrial users in the State paid 52 percent more than average.

California began its recent experience with electricity reform on January 1, 1998, when Assembly Bill 1890 (A.B. 1890) became effective. Influenced strongly by electricity reforms undertaken in the United Kingdom almost a decade earlier, California created a new means of electricity exchange and allowed consumers greater choice in selecting their electricity suppliers. California's reforms implemented a pricing mechanism that would recover "stranded" electricity costs, most of which were related to past investments in nuclear power and uneconomical power purchase contracts. To ensure that consumers benefited during the transition period, California required that the State's three major utilities provide their residential and small commercial customers a 10-percent rate reduction, freezing rates at 10 percent below the prevailing rates as of June 10, 1996, until at least April 2002. What was essentially a performance-based rate (PBR) system was adopted during the transition period.[c]

California's electricity reform addressed the industry's stranded cost problem. Stranded costs were allocated to all classes of customers in accordance with the amount of electricity they consumed. The State has attempted to pay down stranded costs through the issuance of bonds to be financed over a transitional period, but in practice the financing of the bonds added to consumers' electricity bills and offset some of the impact of the rate reduction discussed above. In essence, the rate reduction was financed by the bonds used to recover the stranded costs, and the costs of the financing were transferred to consumers. The financing is due to be completed either by March 31, 2002, or at the time that all authorized costs for utility generation assets (stranded costs) have been recovered.

A.B. 1890 provided customer choice by allowing more than 70 percent of California's electricity customers to change providers. By the time the retail market was opened to competition, 250 power marketing companies had signed up to sell electricity directly to California consumers.[d] Consumers have been reluctant, however, to switch from their incumbent suppliers. They may have been discouraged by the retail rate caps and by the fees charged for making a switch. The multinational conglomerate Enron, for instance, exited the California retail market only 2 months after beginning operation, due to a low consumer signup rate. Whatever the reason, the introduction of electricity marketing in California was less successful than it has been in the Scandinavian countries, Australia, and the United Kingdom.

A.B. 1890 attempted to reconstruct California's electricity supply industry along its three distinct components: generation, transmission, and distribution. An electricity pool, the California Power Exchange (PX), and an Independent System Operator (ISO) were created. The California PX and ISO were launched in March 1998. The ISO was given a mandate to operate the high-voltage transmission lines owned by the State's three dominant investor-owned utilities, Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric.

The purpose of the PX is to act as a market for buying and selling electricity. All investor-owned utilities are required to compete in a power pool to sell their electricity, and independents may compete in the pool on a voluntary basis. The power pool works in the following fashion: suppliers and consumers of electricity submit bids to the PX for electricity needed both during the next day and during the next hour time periods. The PX then calculates the resulting demand and supply curves to determine a market clearing price.

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[a]For a description of the electricity reforms undertaken in the United Kingdom, see Energy Information Administration, *Electricity Reform Abroad and U.S. Investment*, DOE/EIA-0616 (Washington, DC, October 1997).

[b]Energy Information Administration, *Electric Power Annual 1997*, Vol. II, DOE/EIA-0348(97/2) (Washington, DC, October 1998), p. 22.

[c]Performance-based rates are essentially caps on prices, rather than on profits as was the case under the earlier method of regulation. Performance-based ratemaking is intended to allow electricity suppliers to profit more directly from efficiency gains and thereby have a greater incentive to cut costs.

[d]J.R. Emshwiller and K. Kranhold, "California's Power Deregulation Isn't As Open As It Looks," *Wall Street Journal* (February 17, 1998), p. B2.

U.S. Electricity Deregulation: The California Experience (Continued)

In 2000, much attention was focused on the performance of California's recently deregulated electricity market. In its third year of operation, the newly reformed electricity sector faced an exceptionally hot weather spell in May 2000, which led to electricity supply problems. Among other factors, the problem was exacerbated by a 3-year drought in the Northwest that significantly reduced the hydroelectric capacity available to the western States; the constrained capacity of transmission lines to bring more electricity into California; the reduced availability of some power plants because they had used their allotted emission allowances and because of their extended use during the previous summer; and the high cost of purchasing emission allowances, which would have allowed the plants to continue to operate.[e]

Exceptionally high natural gas prices also contributed to California's runup in electricity prices. Insufficient pipeline capacity both at the border and within the State severely limited available gas supplies, and border prices spiked to more than six times the New York Mercantile Exchange (NYMEX) price.[f] In May, the California ISO had to request industrial customers and other large users, who had agreed to reduce demand when asked, to take those steps. In June 2000, the exceptionally hot weather and a grid operational problem led to rolling blackouts in the San Francisco Bay area.[g] The Bay Area's local utility, Pacific Gas & Electric, was forced to interrupt service to 100,000 customers.

In the summer of 2000, both Pacific Gas & Electric and Southern California Edison were operating under retail rate caps that are scheduled to be in affect until April 2002 according to A.B. 1890. Customers of San Diego Gas & Electric (SDG&E), however, were the first to see rate caps removed, and their electricity bills rose sharply. In the California PX, ancillary prices reached $9,999 per megawatthour.[h] The high wholesale power prices led to concerns that power producers could be exercising market power, and SDG&E asked the Federal Energy Regulatory Commission (FERC) "to declare California markets uncompetitive and to impose [price] controls."[i] SDG&E had at the time been passing on its sharply higher purchased wholesale power costs to its retail consumers. Electricity bills in San Diego tripled.

In August, California Governor Gray Davis directed the State's Attorney General to investigate whether "possible manipulation in the wholesale electricity market" had occurred.[i] In September 2000, the governor signed legislation that would cap San Diego electricity prices for residential and small commercial users at 6.5 cents per kilowatthour—less than half the average price in August—retroactive to June 1, 2000. The governor also directed the California Energy Commission to expedite siting reviews for new power plants.[i] In August, in order to address the problem of inadequate long-term electricity capacity, the governor signed A.B. 970, accelerating the power plant approval process from 12 months to 6 months.[j]

California's electricity troubles continued to deepen toward the end of 2000 and into the beginning of 2001. In December, the price of electricity skyrocketed to 30 cents per kilowatthour.[k] With their ability to raise retail electricity prices restricted, and facing exceptionally high pool prices, Pacific Gas & Electric and Southern California Edison defaulted on hundreds of millions of dollars in debt and power bills. Together, the two utilities accumulated more than $12 billion in debt as a result of the sharp rise in California pool prices, and both utilities have seen their debt downgraded to below investment grade status.[l] On the consumer side, the retail price caps shielded electricity customers from the impacts of the market price spikes, and there was no price pressure to encourage demand reductions. In early 2001, the State experienced a series of short-duration, rolling blackouts in which more than 675,000 homes and several large industrial users lost electric power.[m]

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[e]Energy Information Administration, "The California Electricity Situation: Subsequent Events," web site www.eia.doe.gov/cneaf/electricity/california/subsequentevents.html (January 29, 2001).

[f]"California Haunted by Neglect of Infrastructure," *Natural Gas Week* (December 18, 2000), p. 11.

[g]Michael Kahn (Electricity Oversight Board) and Loretta Lynch (California Public Utilities Commission), "California's Electricity Options and Challenges: Report to Governor Gray Davis."

[h]Ancillary services are those services necessary to support the transmission of energy from resources to loads while maintaining reliable operation. They include reactive power supply, voltage support, regulation, and frequency control, among other things.

[i]"California Looks in Every Direction Seeking 'Fix' for Power Market Shock," *Electric Utility Week* (August 7, 2000), p. 1.

[j]Energy Information Administration, "Status of State Electric Industry Restructuring Activity," web site www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html.

[k]R.L. Olson, "Power: Who is the Real Freeloader," *Los Angeles Times* (January 17, 2001), p. A13.

[l]"California's Power Crisis, A State of Gloom," *The Economist* (January 20, 2000), p. 55.

[m]D. Whitman, "California Unplugged," *U.S. News and World Report* (January 29, 2001), p. 26.

U.S. Electricity Deregulation: The California Experience (Continued)

High wholesale prices in California have contributed to higher prices in neighboring States, resulting in a regional electricity crisis that has caused several State governors to ask for wholesale price caps.[n] In December 2000, FERC capped bulk power prices at $150 per megawatthour, although both newly elected President Bush and the recently appointed Commissioner of FERC have opposed price caps.[o] Generating companies could petition for higher prices, however, if they could justify them.[p] The FERC had undertaken an investigation of California's electricity market and market structure in July 2000 as part of an investigation examining the national electricity market.

On November 1, 2000, FERC released a draft order calling for changes in California's market, recommending that the State build more power plants and invest more in transmission lines.[q] The Commission also proposed eliminating the requirement that California's major utilities buy and sell all their electricity through the pool, and recommended that they be allowed to engage in long-term forward contracts.

In December 2000, the U.S. Secretary of Energy, Bill Richardson, issued an immediate order forcing 75 power generators in western States to supply electricity to California. He further ordered that power producers sell power to California "even if they are uncertain of payment."[r] In January 2001, Governor Davis signed an emergency order allowing California's Department of Water Resources to become a temporary buyer of power, providing the agency with a spending authority of $400 million, and in February 2001 he signed a measure allowing the Department to float an estimated $10 billion in revenue bonds to finance power purchases directed at acquiring electricity through long-term contracts. The bonds are to be paid off by electricity consumers. The bill also includedsome conservation measures, requiring retailers to cut their outdoor lightning use by half or face penalties. In March 2001, the FERC ordered 10 generation companies to reimburse the California ISO $69 million for charging rates deemed not to be "just and reasonable." The reimbursement amounted to only a fraction of the $550 million sought by State officials for overcharges.[s]

Sharp price spikes are not new to pool-based electricity exchange systems. In countries that have adopted pool-based electricity trading systems, such as the United Kingdom and Australia, concerns have arisen about the connection between price spikes and market power. In the wake of California's recent experience with its electricity pool, a similar concern has arisen that suppliers may have achieved excessive market power.

Several other arguments have also been offered to explain the problems experienced by California's electricity market in 2000. Long-term underinvestment in the State's electricity sector has been cited as a contributing factor, given that its rapidly growing economy has produced sharp increases in electricity demand. It has become increasingly difficult to build new generation facilities in the State, and generation capacity additions have severely lagged far behind growth in demand since the early 1990s. The average age of a power plant in California is currently more that 30 years.[t] Indeed, operational difficulties have plagued California's electricity infrastructure over the past year. During the height of the electricity crisis several power plants were pulled out of production, and congestion constraints became apparent on the State's north-south transmission line.

[n]R. Smith, "Governors Seek Caps on Prices of Electricity," *Wall Street Journal* (February 5, 2001), p. A3.

[o]The newly appointed FERC Commissioner has spoken out against price caps. Commissioner Hebert agreed to the $150 per megawatthour price cap only after the cap's duration was shortened from 24 months to 14 months. See R. Smith, "Regulators Step In To Ease Price Shocks in California's Deregulated Power Market, *Wall Street Journal* (December 18, 2000), p. A2.

[p]R. Smith, "U.S. Panel Proposes Big Market Change To Curb California's Electricity Prices," *Wall Street Journal* (November 2, 2000), p. A3.

[q]N. Banerjee, "U.S. Proposes Change in Electricity Market," *New York Times* (November 2, 2000), p. A26.

[r]"Unpaid, California's Small Power Suppliers Begin To Shut Down," *Wall Street Journal* (February 1, 2001), p. A4; and D. Morain and N. Vogel, "U.S. Sets Rules To Ensure Electricity Sales to State Utilities," *Los Angeles Times* (December 15, 2000), p. A1.

[s]J. Kahn, "Federal Agency Orders Power Generators To Justify Prices," New York Times (March 10, 2001), p. A6.

[t]Michael Kahn (Electricity Oversight Board) and Loretta Lynch (California Public Utilities Commission), "California's Electricity Options and Challenges: Report to Governor Gray Davis."

National Grid Group, PLC, of the United Kingdom purchased New England Electric System in 2000 and reached a merger agreement with Niagara Mohawk of New York in 2001. This merger, if carried through, is expected to be valued at $3.2 billion along with the assumption of $5 billion in debt [***15***]. British Energy has formed a joint venture with PECO Energy, AmerGen, which has been responsible for some of the largest acquisitions of electricity generation assets to date.

Two electricity generation companies in the United Kingdom, National Power and PowerGen, have also acquired U.S. electricity assets. PowerGen is the United Kingdom's second largest generating company, after

National Power. In February 2000, LG&E Corporation announced its intended merger with PowerGen. The estimated value of the transaction was $3.2 billion, and the combined company will have assets of $12 billion. American National Power, the Texas-based subsidiary of National Power, currently has 9,000 megawatts of power capacity under development in the United States [***16***]. National Power is expected to have 4,000 megawatts of capacity in operation in the United States by 2004 [***17***].

Japanese and French companies have also started to invest in U.S. electricity assets. In November 1999, Tokyo Electricity Power Company and Mitsubishi Corporation each purchased a share in Orion Power Holdings. Orion is a joint venture between the investment bank, Goldman Sachs, and the Baltimore-based utility, Baltimore Gas & Electric. The Japanese company Marubeni and the French conglomerate Vivendi had taken a 30-percent interest in the U.S. independent power producer, Sithe Energies.

Regulatory Developments

At the end of 2000, more than half the States had adopted legislation or issued regulatory orders in an attempt to introduce reforms in their electricity markets [***18***]. Reforms have been most prominent in those regions with exceptionally high electricity prices, such as California and the northeastern United States. Changes in technology have also driven reform. Through the 1960s and 1970s, electricity generation grew more efficient with size, or marginal costs declined as generation units got larger. Since then, however, the trend has been for maximum efficiencies to be increasingly achieved at relatively smaller generation capacities. This development has forced a reappraisal of the idea that generation is a natural monopoly and has brought to the fore the idea that competition in generation is achievable.

States have had to address a number of issues in deregulating their electric utility markets. One issue concerned the vertical separation between the generation business and the wires (distribution and transmission) business. In recent years, much merger and acquisition activity has been driven by State-mandated asset sales in order to separate the ownership of generation assets from distribution assets. Another major concern was the issue of how to finance stranded costs.

States' efforts at encouraging utilities to shed their generation assets have increased the role of nonutility generators. Utilities sold 50,888 megawatts of capacity in 1999 to nonutility electricity providers [***19***]. These nonutility electricity providers had 167,357 megawatts of installed capacity in 1999, up from 70,254 megawatts in 1995. Nonutility generating facilities accounted for 15 percent of the market in 1999, up from 11 percent in 1998.

Mexico

Mexico has for several years debated the possibility of privatizing its electricity sector. Some progress towards privatization was made when Mexico opened up its generation market to independent power producers in 1996. In December 2000, Mexico witnessed an historic change of government with the party holding the Mexican presidency for the past 71 years (the Institutional Revolutionary Party, or PRI) relinquishing the Mexican presidency to an opposition party, the National Action Party (PAN). President Fox has pledged to submit an electricity bill which is expected to grant private investors greater latitude in investing in Mexico's electricity sector. Mexico has seen its electricity consumption grow at an annual rate of 6 percent between 1994 and 1999 [***20***].

Japan

Japan's decade-long economic malaise continues to restrain that nation's electricity consumption growth. While the U.S. economy expanded an estimated 33 percent between 1990 and 1999, Japan's economy grew by 13 percent. Japan's economic growth rate is expected to average 1.3 percent between 1999 and 2010 and 1.7 percent between 2010 and 2020. Electricity growth in Japan is expected to trail GDP growth and average 1.3 percent between 1999 and 2020.

Japan has some of the highest electricity prices in the world. As a result, the nation is currently undertaking electricity reforms in an attempt to reduce these prices. In March 2000, the retail supply sector for high-volume users (over 2 megawatts) was liberalized. Large customers were allowed for the first time to choose their electricity suppliers, and electricity suppliers were allowed to sell outside of their traditional franchised territories.

Western Europe

In 1996, the 15 members of the European Union adopted its electricity directive. The directive became effective in February 1997. The goal of the directive was the eventual establishment of a single European electricity market. A single market would foster competition and reduce the price of electricity to consumers. The electricity directive called for the member nations to open at least 26 percent of their national markets to competition by February 1999.[23] By the year 2000, the signatories were expected to expand this share to 30 percent and to 35 percent by 2003. The directive establishes uniform rules for all aspects of electricity supply and calls for the unbundling of separate energy services: generation, transmission, and distribution. The purpose behind unbundling is to

[23]Belgium and Ireland were given an additional two year grace period to catch up with other European Union members to abide by its electricity directive. Belgium chose to wave its grace period. Greece was given three years.

avoid discrimination and cross-subsidization. The directive allows for a choice between negotiated third-party access and a single-buyer model.

Electricity is a "network" industry. European electricity deregulation has taken place in the context of a general effort at deregulating network industries, such as natural gas, telecommunications, rail, trucking, postal services, airlines, water, etc. The purpose of the EU electricity directive was to reduce the price of electricity through greater competition and to move away from monopoly power to a freer market. European electricity has long been characterized by national monopolies with sole domain over home territories.

An important element of the EU electricity directive is the requirement that electricity services become unbundled. This has had a marked impact upon the way companies have begun to offer services and on the way the industry is structured. Unbundling has separated generation services from transmission and distribution services. Unbundling has also promoted the growing importance of marketing and trading of electricity as separate services.

Germany has been the most aggressive of the EU nations in implementing the electricity directive. Instead of phasing in competition over a number of years as called for in the directive, the German government opened up its electricity market to unrestricted competition in 1998. The resulting sharp decline in German electricity prices was an unexpected benefit from this decision; German industrial electricity rates, once among the highest in Europe, are now lower than in any Western European country except hydro-intensive Norway and Finland [***21***]. Between 1996 and 1999, German electricity prices to industrial consumers are estimated to have fallen 29 percent, while residential consumers have seen a 14-percent reduction in prices [***22***]. In 1999, German industrial electricity prices averaged 6.28 cents per kilowatthour (in 1998 dollars), as compared with 8.87 cents per kilowatthour in 1996.

In contrast to Germany, France has only reluctantly accepted the requirements under the EU electricity directive. In June 2000, the European Commission took legal actions against the French government for its failing to incorporate the directive into French law. Germany's government has threatened to bar imports of electricity from any country which fails to abide by the directive's call for the opening of national electricity markets to competition. Electricite de France is the largest utility in the world and has exclusive control over the French electricity market. Electricite de France has promoted the idea of a single-buyer model over the open-access system.

Today the most open electricity markets in Europe exist in the United Kingdom, the Netherlands and Scandinavia, followed by Spain and Italy. Largely due to political factors and the relative strength of national utilities, Portugal, France, and Belgium have lagged the other European Union member countries in opening up their electricity sectors to competition.

Eastern Europe and the Former Soviet Union

The FSU and much of Eastern Europe suffer from an antiquated electricity generation and transmission infrastructure. Although electricity demand is expected to be 47 percent higher in 2020 than in 1999, the region is not expected to see much in the way of capacity expansion, although the fuel mix will involve a movement away from coal to natural gas. Rather, future investment will be directed in large part to upgrades, in efforts to bring the region's electricity industry up to the standards of those in the industrialized nations.

Developing Asia

Of all world regions, Asia is expected to show the most robust rate of growth in electricity consumption over the forecast period. Electricity demand in developing Asian nations is expected to grow by an average of 4.5 percent per year between 1999 and 2020. Developing Asia accounted for 18 percent of worldwide electricity consumption in 1999, and by 2020 it is expected to account for 26 percent.

Coal, which supplied 54 percent of the fuel used to generate electricity in developing Asia in 1999, is expected to maintain that level by and large, declining only slightly to 52 percent in 2020. In the rapidly growing Asian energy market, coal consumption in absolute terms is expected to more than double over the same period. Nuclear, renewables, and oil are expected to lose market share. Natural gas is the only fuel that is expected to increase its share of the Asian electricity market, from 9 percent in 1999 to 11 percent in 2020.

The financial and economic crisis that started in Thailand and quickly spread to other economies of Southeast Asia in mid-1997 has eased considerably. By 1999, most Asian nations began to show positive rates of economic growth.

Private investment in developing Asian power projects has slowed considerably, after several years of rapid growth. The reduction can be attributed in part to the 1997-1999 economic recession; however, the slowing trend has continued well into the region's economic recovery. Most of the investment now occurring is directed toward adding to the region's generation capacity. Among the developing nations, the decision to sell off complete electric utilities wholesale to private (including foreign) investors has largely been a South American phenomena; developing Asian nations have been much slower than the nations of South America to privatize national electricity assets.

Privatization efforts in developing Asia have consisted largely of allowing private participation in new generation (greenfield) investments. Until recently the Philippines appeared ready to depart from the trend by privatizing its state-owned utility, Napocar; but the recent ouster of the Estrada government has delayed the Napocar privatization plan despite the earlier commitments the government had made.

In several nations of developing Asia, electricity pools or transmission interlinkages are being developed to provide better capacity management and to facilitate trade in excess power. China, Indonesia, South Korea, the Philippines, and Thailand have announced plans to develop national electricity pools. In the process of liberalizing its electricity market, South Korea intends to begin a power pool in 2003 [***23***]. The initial phase of South Korea's electricity reform efforts also intends to allow industrial users to choose their electricity suppliers. Similarly, in an effort to induce more competition in electricity generation, the Chinese government is promoting an electricity pool over the formerly used bilateral contract arrangements.

China

Overall, China is expected to add more to its electricity generation capacity between 1999 and 2020 than any other nation in the world—for example, more than twice the capacity additions projected for the United States. China is far and away developing Asia's largest economy, accounting for roughly one-third of the region's economic activity. China has also had the region's fastest rate of economic growth in recent years. Although its rate of economic growth has slowed over the past year or two, the Chinese economy was not dramatically affected by Asia's economic crisis.

China's current 277,000 megawatts of installed electricity capacity is second only to that of the United States [***24***]. Electricity consumption is expected to grow at a 5.5-percent annual rate over the 1999-2020 period. China's fast pace of future electricity consumption growth is due in part to its current underdeveloped electricity sector. Per capita consumption of electricity is currently one-twentieth of that in the United States.

Coal currently accounts for 65 percent of China's electricity fuels market, and its share is expected to decline slightly through 2020. Clearly, however, if the Kyoto Climate Change Protocol or a successor policy with similar provisions is enacted, China could become an ideal candidate for joint implementation agreements to mitigate growth in carbon emissions.

China has the world's second largest coal reserves and is both the world's largest producer and consumer of coal. However, its coal reserves generally lie in the interior region of the country, far away from coastal economic activity. China is currently promoting the building of minemouth electricity plants rather than constructing additional rail lines to transport coal to eastern regions [***25***].

After coal, renewables account for the second largest share of China's electricity market, with a 26-percent overall share in 1999. China's consumption of renewable energy (mostly hydroelectricity) is expected to double between 1999 and 2010 and to increase its share of China's total electricity market. By the time it becomes fully operational in 2009, the $30 billion Three Gorges Dam will have an installed capacity of 18,200 megawatts of power. When it is completed, Three Gorges will be the largest dam in the world, five times wider than the Hoover Dam in the United States [***26***]. After 2010, growth in renewable energy is expected to moderate, and its share of the electricity market is expected to start to fall.

Although nuclear power currently accounts for a very small share of China's electricity market (approximately 2 percent in 1999), the Chinese government has an ambitious plan for additional nuclear power over the next two decades. By the end of the forecast period, nuclear power plants are expected to supply nearly 6 percent of the electricity used in China.

During the late 1980s, China implemented electricity reforms aimed at reducing government's managerial role in electricity supply [***27***]. The government allowed for a "fuel cost rider" in 1987, permitting generation companies to pass on higher fuel input costs to consumers [***28***]. More recently, price reforms have been undertaken to increase the attractiveness of investments in China's electricity sector, which had periodically suffered from capacity shortages. One such reform was implemented in 1996 during the financing negotiations surrounding the Laiban B project (a 700-megawatt coal plant). In awarding the contract for the financing of Laiban B, rather than negotiating an allowable rate of return, China's government chose to auction off the project to bidders offering the lowest tariff per kilowatt. Before the Laiban B deal, foreign investors had often criticized China's allowable rates of return on electricity investment for being too low.

Price reform is another means by which the Chinese government has attempted to attract private capital investment in electricity. In 1998, China deregulated electricity prices for rural areas [***29***]. In 1999, China's government announced plans to allow generators to bid competitively for access to power networks [***30***].

India

Second only to China among developing countries in terms of population and economic activity, India is expected to increase its consumption of electricity at a 3.9-percent annual rate over the forecast period. Heavy reliance on coal as an electricity fuel is expected to lessen somewhat, with coal's share of the market declining from 76 percent in 1999 to 65 percent in 2020. Natural gas and nuclear power will largely make up for coal's lost share. In 2020, natural gas is expected to account for 11 percent of India's electricity fuels market, up from 5 percent in 1999. The nuclear share is expected to increase from 2 percent in 1999 to 6 percent in 2020.

As in China, foreign investment will play a key role in the financing of India's power sector expansion. The Indian government opened up the power sector to private investment in 1991 with the passage of an amendment to the 1948 Electricity Supply Act that allowed for the construction of independent power projects.

In December 1996, the Indian central government announced its policy for electricity development [***31***]. Called the "Common Minimum National Plan for Power," the policy intends to restructure and corporatize the state electricity boards, to allow them greater autonomy, and to allow them to operate along commercial lines. The plan also attempts to ease the approval process for private power projects selected for competitive bidding by the central government. In June 1998, the central government went several steps further and eased its rules for foreign investment in the power sector. Automatic approval is to be given to projects costing in excess of 15 billion rupees (about $355 million) that involve 100 percent foreign equity.

The removal of subsidies flowing from urban electricity consumers to rural users has been a serious issue as India has undertaken electricity reform. The subsidies have been substantial, and their removal would in some Indian regions lead to sizable increases in rural electricity rates. The Indian government's Electricity Regulatory Commission issued an ordinance in 1998 directed at rationalizing electricity tariffs and subsidy policies. Under the new ordinance, the state regulatory entities would have the authority to remove rural subsidies [***32***].

India is also in dire need of an upgrade of its transmission system. Currently, as much as 20 percent of India's electricity is lost [***33***], much of it through "nontechnical" losses from theft or leakages and from errors in meter reading, accounting, and billing procedures [***34***].

Other Developing Asia

Developing Asian nations other than China and India also are expected to see rapid growth in electricity consumption over the coming years. Although in 1997 and 1998 many Asian economies slipped into recession—some for the first time in recent memory—by the end of 1999 most were showing signs of strong economic recovery. Electricity consumption for the collective region is expected to grow at a 3.3-percent annual rate between 1999 and 2020.

The Asian economic crisis took a particularly heavy toll in Thailand, where electricity demand has not yet returned to its pre-crisis rate of growth [***35***]. The Electricity Generating Authority of Thailand (EGAT), Thailand's state-owned electricity company, has postponed or delayed a number of projects, including two 300-megawatt plants at Ratchaburi. Ratchaburi eventually is expected to have 3,200 megawatts of generating capacity, and it is expected to be privatized by the Thai government [***36***]. Thailand's electricity reform plan, which also involves the creation of a national pool, calls for the unbundling of the electricity industry's generation, transmission, and distribution components before they are privatized.

In 1999, the region as a whole depended most heavily on coal (which supplied 29 percent of electricity) and oil (21 percent). No other world region outside the Middle East currently depends so heavily on oil as a source of electricity generation, and oil's share in the region is not expected to change over the forecast period. Renewable energy use in other developing Asia is projected to decline in importance, falling to 15 percent of the electricity fuels market by 2020 from 22 percent in 1999. Little additional nuclear capacity is expected to be built in other developing Asia, with the exceptions of Taiwan and South Korea.

Natural gas is expected to supplant oil and renewables in large measure. From 22 percent of the region's electricity fuels market in 1999, the natural gas share is expected to increase to 27 percent by 2020. In the near term, growth in natural-gas-fired generation is hampered by a lack of transportation infrastructure. For instance, virtually all of Taiwan's natural gas demand is met by imported LNG. In the long term, natural gas supplies might arrive via pipelines connecting the Caspian sea region with China and perhaps Japan, and natural gas pipelines may some day connect gas reserves in Indonesia to electric power plants in other Southeast Asian nations.

Africa

South Africa accounts for almost one-half of the electricity generated on the African continent, and South Africa, Egypt, Algeria, Libya, and Morocco together account for nearly three-quarters of the continent's total electricity production. Africa as a whole is expected to see electricity consumption grow at a 3.8-percent annual rate over the 1999-2020 projection period. No other region has as little access to electric power as Africa. Coal provided roughly half of the region's electricity production in 1999, and in 2020 its share is expected to be 36 percent.

Several African countries have recently opened their electricity sectors to private investment. In Morocco, the 1,356-megawatt Jorf Lasfar power project was completed and began operating in February 2001 [***37***]. The $1.5 billion coal-fired power plant is the largest independent power plant in Africa and the Middle East to date. Located on the Atlantic coast about 78 miles southwest of Casablanca, the plant now generates more than one-half of Morocco's total electricity supply and accounts for about 35 percent of its installed capacity. Jorf Lasfar is jointly owned by CMS Energy and the Swedish / Swiss company, Asea Brown Boveri. Electricity from the project is sold to the country's state-owned utility, Office Nationale de l'Ectricite (ONE) under a 30-year purchase agreement. Egypt's cabinet in 1996 approved the startup of a BOT program involving 1,600 megawatts of power [***38***].

In the Ivory Coast, the government launched plans for privatizing many of its public entities in 1990 [***39***], beginning with the national electric utility, Compagnie Electricite Ivoirienne (CIE), which is now jointly owned by two French companies, Electricite de France (EDF) and Saur-Bouygues. In 1993, the two companies began the joint development of Compagnie Ivoirienne de Production d'Electricite (CIPREL), one of the first independent power projects in sub-Saharan Africa. The gas-fired plant began providing electricity to the country's national grid in 1997 with an initial capacity of 100 megawatts, which was expanded to 210 megawatts in 1998. The country has seen growing interest in development of its electricity sector in recent years. In addition to EDF and Saur-Bouygues, Asea Brown Boveri began work as part of the Cinergy consortium (along with EDF and Industrial Promotion Services, an affiliate of the Aga Khan Fund for Economic Development) on several thermal power projects in the Ivory Coast. Moreover, French electricity and transportation company Clemessy has been contracted to electrify 100 Ivory Coast villages, which is scheduled for completion by the second quarter of 2001.

Nigeria is also attempting to encourage foreign participation in electricity generation. In late 1998, Mobil, one of the largest producers of oil in Nigeria, announced that it had contracted to build a 350-megawatt natural-gas-fired independent power project in Nigeria [***40***]. Early in 2000, Nigeria gave ExxonMobil permission to build and operate a 350-megawatt gas-fired power station in the Niger Delta area [***41***]. In June 2000, the country signed an agreement with Enron for a 270-megawatt electricity project in Lagos. Nigeria is also negotiating with Shell and Texaco to establish private power plants that could provide an emergency electricity supply. The country has faced serious electricity shortages for the past several years because of declining generation from domestic power plants.

In March 1999, Senegal announced the privatization of its electric power industry. In that same month, the Senegalese government sold 34 percent of the shares of the Société Nationale d'Électricité (SÉNÉLEC), to the French-Canadian consortium, Hydro-Quebec-International-ELYO (HQI-ELYO) for $69 million (U.S. dollars) [***42***]. As a result, the HQI-ELYO consortium became responsible for managing all electricity production, transmission, and distribution activities associated with SÉNÉLEC.

Algeria's Parliament is currently debating legislation that would end the monopoly held over power production by the Algerian state utility, Sonelgaz, by allowing independent power production [***43***].

Middle East

Almost two-thirds of the Middle East region's economic output is accounted for by Iran and Saudi Arabia, along with half the region's electricity consumption. Iran is the most populous country in the Middle East, and Saudi Arabia has one of the highest per capita incomes. Other large users of electricity in the Middle East include Israel, Iraq, and Kuwait. Largely as a result of growth in the region's dominant economies, electricity consumption in the Middle East is expected to grow at a 3.4-percent annual rate over the projection period.

The Middle East depends heavily on petroleum to fuel its electricity generation. In 1999, oil-fired generation accounted for 35 percent of all electricity produced and natural gas 41 percent. That level of dependence is expected to continue over the forecast period. Over the next few years, Iran is expected to enter the league of nations owning nuclear power reactors, and by 2020 nuclear power is expected to account for 1 percent of the region's electricity production.

A five-country electricity transmission network is being developed by Egypt, Iraq, Jordan, Syria, and Turkey. The project, which is expected to cost $450 million, would save the countries an estimated $2 billion a year by allowing them to share excess capacity at times of peak demand [***44***]. In March 2001, Jordan and Syria are expected to inaugurate the Syrian / Jordan component of the regional electricity grid. Links are expected to be established between Syria and Turkey by the end of 2001 and between Lebanon and Syria by 2002 [***45***].

Among Middle Eastern nations, Israel took a step towards privatization recently. In 1996, Israel's parliament passed a new electricity law allowing the Energy

Minister to grant permits to independent power producers [*46*]. In keeping with the privatization effort, the Israel Electric Company (IEC), Israel's national utility, has been directed by the Energy Minister to purchase 900 megawatts of power from independent power producers by 2005 [*47*].

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